Introduction to Rate Design and Cost Allocation

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Missouri Public Service Commission

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Purpose of Cost Allocation/Rate Design

• Determine whether each class of customers is providing the utility with a reasonable level of revenue necessary to cover the investments and costs of providing service to that class.

• Determine class revenue requirement/responsibility of each class for its equitable share of the utility's total annual cost of providing service within a given jurisdiction.
  – Creates pricing signals that encourage efficient use of system capacity.
  – Avoids undue price discrimination among classes of customers.
Rate Design and Cost Allocation

• Rate design for electric utility customers is an arcane topic that matters a lot. Rate design represents the price signals consumers use to guide their consumption and investment choices. Just as customers choose groceries, gasoline, or plane tickets in part based on the price for the time and quantity they need, they also choose when and how much electricity to consume based on price.
Cost Allocation

• Dividing up the Revenue Requirement (Costs)

• Imbedded Cost Studies
  ➢ Historical Cost Studies
  ➢ 30 States use Imbedded Cost Studies

• Marginal Cost Studies
  ➢ Forward Looking Studies
  ➢ 20 State use Forward Looking Studies
Cost Allocation

- Cost of Service study is an analysis of the total costs a utility incurs to provide service.
  
  * Plant Investment – production, transmission, storage, distribution & general
  
  * Expenses
    - Operation and Maintenance
    - Administrative and General
    - Labor
    - Taxes

- Class Cost of Service study is an analysis of the total costs incurred by a utility and allocated to various rate classes.
Cost Allocation (Cont’d)

- Class Cost of Service Study will:
  Step 1: Functionalize Costs
  Step 2: Classify Cost
  Step 3: Allocate Costs

- At each step ask, “What caused the cost to be incurred?”
Functionalization

- The grouping of plant investment and operation expense accounts according to the specific function they play in the operations of the utility system.
  - Production
  - Storage (Natural Gas Only)
  - Transmission
  - Distribution
  - Customer
  - Administrative and General
    - Classified as production, transmission, distribution and customer.
Total Functionalized Costs of a Vertically Integrated Electric Utility

- Production-Capacity: 38%
- Production-Energy: 35%
- Distribution: 18%
- Transmission: 4%
- Customer: 5%
Total Functionalized Costs of a Natural Gas Utility

- Distribution: 76.04%
- Customer: 21.04%
- Production: 0.72%
- Transmission: 0.03%
- Storage: 2.17%
Classification

- Classification is a means to divide the functionalized, cost-defining components into:
  - Customer Related Costs
    - Costs that vary with the number of customers
  - Demand Related Costs
    - Costs that vary with kW of peak demand
  - Energy Related Costs
    - Costs that vary with kWh of energy
Allocation

- The process of assigning costs to different customer classes.
  
  - Customer classes are based on similarities in usage levels, voltage levels at which the customer is served and other conditions of service, such as demand meters.
  
  - Customer Categories Include:
    - Industrial (Transmission, Substation, Primary and Secondary)
    - Commercial (Primary and Secondary)
    - Residential (Secondary)
- Bulk transmission lines: 230-500 kV
- Network switchyard
- Transmission subs (step-down transformers)
- 66-110 kV lines
- Distribution subs (step-down transformers)
- Distribution lines (pole-top transformers)
- ‘Bulk’ transmission lines: 230-500 kV
- Customer Served at Transmission
- Customer Served at Primary Voltage

Generation (6-14 kV)

Demand-Energy

Demand

Demand-Customer
Foundation For Demand Allocators

- **Average Demand** – total kWh during a cycle divided by the number of hours in the cycle.
  - 8760 hours in a year

- **Peak Demand** – is the maximum hourly demand (load) during the cycle (measured in kW or MW).
  - **Coincident Peak Load (CP)** – a customer class’s peak load at the time of total system peak.
  - **Non-Coincident Peak Load (NCP)** – a customer class’s peak load regardless of when it happens.
    - **Customer Maximum Demands (MDD)** – sum of individual customer demands within a specific class.
System Load Diversity

[Graph showing System Load Diversity with different load categories: Res (Residential), Sm Com (Small Commercial), Lg Com (Large Commercial), Sm Ind (Small Industrial), Lg Ind (Large Industrial).]

[Legend for the graph showing five different load categories with their respective colors and markers.]

[The x-axis represents hours from 1 to 24, and the y-axis represents load levels from 0 to 2000.]
Natural Gas Conversions

- 1 Cubic Meter = 35.31 Cubic Feet
- 100 cubic feet (1 ccf) ≈ 2.83 m³
- 1 Therm = 100,000 Btu ≈ 1 ccf
- 1 Million British Thermal Units (MMBtu) = 10 Therms ≈ 1060 Megajoule (MJ)
Methods of Allocation

Demand-Related Cost Allocation Methods

• Coincident Peak Demand (1CP, 4CP, 12CP)

• Non Coincident Peak Demand (1NCP, 4NCP, 12NCP)
  – Customer Maximum Demands (MDD)

• Average-Excess Demand
  – This method uses a weighted average of the average-demand allocators (weight = system load factor) and the Excess-Demand Allocators (weight = one minus the system load factor).

• Base, Intermediate and Peak (BIP) (Missouri’s Method)
  – The base portion of this method is a weighted average of the average demand allocator (weight = system load factor) and the intermediate and peak portions are a weighted average of the average peak demand allocators (weight = one minus the system load factor).
Retail System Load (Average & Excess)

- **Load, MW**
- **Month**

**Base Energy (Average)**

**4 NCP (Excess)**
Retail System Load Base, Intermediate and Peak (BIP) Method

Load, MW

Months

4CP (Peak)

12CP (Intermediate)

Base Energy
Methods of Allocation (Cont’d)

- **Energy-Related Cost Allocation Methods**
  - kWh of Energy Sold or Volumes of Gas Sold
    - kWh at Meter and at Generator
  - Compared to high voltage customers, low voltage customers have higher loss factors because: (1) they are further “downstream” from the generation sources and (2) line losses are inversely related to line voltage levels.

- **Customer-Related Cost Allocation Methods**
  - Number of Customer
  - Weighted Number of Customers – weights can be based on:
    - Average meter costs
    - Average billing costs
    - Average meter-reading costs
Methods of Allocation (Cont’d)

Customer and Demand-Related Allocation

Ex. Distribution Plant Investment in Mains

Customer Component

• Typical cost of main per customer multiplied by the number of customers in the class
  – Length of main directly associated with a typical customer in each class
  – The diameter of the main that would be required to serve that customer

Demand Component

• Estimated peak day demands of each class
Data Requirements To Develop Allocators

Electric Utility Provides:

- Hourly load information per customer class based on load research studies
  - Diversity Factors
- Line Loss Study
- Number of customers served in each customer class at each voltage level
- Monthly usage (kWh) and demand (kW) information for each customer class
  - Number of days per bill cycle
- Customer related cost data
  - Meter and Billing costs
Sample of Data Output

### RESIDENTIAL

<table>
<thead>
<tr>
<th>Month</th>
<th>Secondary</th>
<th>Primary</th>
<th>Sub</th>
<th>Transmission</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan.</td>
<td>425,570</td>
<td>433,503</td>
<td>443,763</td>
<td>446,781</td>
<td>459,586</td>
</tr>
<tr>
<td>Feb.</td>
<td>435,625</td>
<td>443,746</td>
<td>454,249</td>
<td>457,338</td>
<td>470,445</td>
</tr>
<tr>
<td>Mar.</td>
<td>332,148</td>
<td>338,340</td>
<td>346,348</td>
<td>348,704</td>
<td>358,697</td>
</tr>
<tr>
<td>April</td>
<td>277,868</td>
<td>283,048</td>
<td>289,748</td>
<td>291,718</td>
<td>300,079</td>
</tr>
<tr>
<td>May</td>
<td>363,820</td>
<td>370,602</td>
<td>379,374</td>
<td>381,954</td>
<td>392,900</td>
</tr>
<tr>
<td>June</td>
<td>436,761</td>
<td>444,903</td>
<td>455,434</td>
<td>458,531</td>
<td>471,672</td>
</tr>
<tr>
<td>July</td>
<td>492,690</td>
<td>501,874</td>
<td>513,753</td>
<td>517,247</td>
<td>532,071</td>
</tr>
<tr>
<td>Aug.</td>
<td>434,473</td>
<td>442,572</td>
<td>453,047</td>
<td>456,129</td>
<td>469,201</td>
</tr>
<tr>
<td>Sep.</td>
<td>375,921</td>
<td>382,928</td>
<td>391,992</td>
<td>394,658</td>
<td>405,968</td>
</tr>
<tr>
<td>Oct.</td>
<td>260,203</td>
<td>265,054</td>
<td>271,327</td>
<td>273,173</td>
<td>281,002</td>
</tr>
<tr>
<td>Nov.</td>
<td>278,219</td>
<td>283,405</td>
<td>290,113</td>
<td>292,086</td>
<td>300,458</td>
</tr>
<tr>
<td>Dec.</td>
<td>397,515</td>
<td>404,925</td>
<td>414,510</td>
<td>417,329</td>
<td>429,289</td>
</tr>
</tbody>
</table>

### Secondary

<table>
<thead>
<tr>
<th>Month</th>
<th>Secondary</th>
<th>Primary</th>
<th>Sub</th>
<th>Transmission</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan.</td>
<td>400,963</td>
<td>408,438</td>
<td>418,105</td>
<td>420,949</td>
<td>433,013</td>
</tr>
<tr>
<td>Feb.</td>
<td>386,208</td>
<td>393,407</td>
<td>402,719</td>
<td>405,457</td>
<td>417,078</td>
</tr>
<tr>
<td>Mar.</td>
<td>332,148</td>
<td>338,340</td>
<td>346,348</td>
<td>348,704</td>
<td>358,697</td>
</tr>
<tr>
<td>April</td>
<td>225,399</td>
<td>229,600</td>
<td>235,035</td>
<td>236,633</td>
<td>243,415</td>
</tr>
<tr>
<td>May</td>
<td>265,674</td>
<td>270,626</td>
<td>277,032</td>
<td>278,916</td>
<td>286,910</td>
</tr>
<tr>
<td>June</td>
<td>394,217</td>
<td>401,566</td>
<td>411,071</td>
<td>413,866</td>
<td>425,727</td>
</tr>
<tr>
<td>July</td>
<td>434,832</td>
<td>442,937</td>
<td>453,422</td>
<td>456,505</td>
<td>469,588</td>
</tr>
<tr>
<td>Aug.</td>
<td>362,240</td>
<td>368,992</td>
<td>377,726</td>
<td>380,295</td>
<td>391,194</td>
</tr>
<tr>
<td>Sep.</td>
<td>311,068</td>
<td>316,867</td>
<td>324,367</td>
<td>326,573</td>
<td>335,932</td>
</tr>
<tr>
<td>Oct.</td>
<td>175,468</td>
<td>178,738</td>
<td>182,969</td>
<td>184,213</td>
<td>189,493</td>
</tr>
<tr>
<td>Nov.</td>
<td>238,944</td>
<td>243,398</td>
<td>249,159</td>
<td>250,854</td>
<td>258,043</td>
</tr>
<tr>
<td>Dec.</td>
<td>368,986</td>
<td>375,864</td>
<td>384,760</td>
<td>387,377</td>
<td>398,479</td>
</tr>
</tbody>
</table>

### Demand loss rates

<table>
<thead>
<tr>
<th>Category</th>
<th>Secondary</th>
<th>Primary</th>
<th>Sub-Transmission</th>
<th>Transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1.0186</td>
<td>1.0237</td>
<td>1.0068</td>
<td>1.0287</td>
</tr>
</tbody>
</table>

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Allocator Usage

• Using the methods of allocation and the data received from the utility, we assign specific allocators to specific functions.

• A general principal to follow is: *Expenses follow Plant.*
  – For example, production maintenance expenses are allocated using the same methodology as production plant. Same relationship exists for transmission, storage and distribution expenses.
## Results of Class Cost of Service

- Total cost to serve a class = Expenses + Return on Investment

<table>
<thead>
<tr>
<th>Functional Category</th>
<th>Residential</th>
<th>Commercial Primary</th>
<th>Commercial Secondary</th>
<th>Industrial Primary</th>
<th>Industrial Secondary</th>
<th>Industrial Substation</th>
<th>Industrial Trans.</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production – Demand</td>
<td>$128,140,056</td>
<td>$440,413</td>
<td>$38,233,710</td>
<td>$31,571,581</td>
<td>$12,553,553</td>
<td>$10,868,441</td>
<td>$6,685,527</td>
<td>$227,973,813</td>
</tr>
<tr>
<td>Transmission</td>
<td>$9,532,613</td>
<td>$47,252</td>
<td>$3,577,149</td>
<td>$3,344,128</td>
<td>$1,280,761</td>
<td>$1,174,899</td>
<td>$677,307</td>
<td>$19,114,641</td>
</tr>
<tr>
<td>Distribution - Substations</td>
<td>$4,706,569</td>
<td>$17,185</td>
<td>$1,190,944</td>
<td>$1,021,363</td>
<td>$396,497</td>
<td>$346,264</td>
<td>$0</td>
<td>$7,159,353</td>
</tr>
<tr>
<td>Distribution - Primary</td>
<td>$17,272,306</td>
<td>$68,760</td>
<td>$4,765,036</td>
<td>$4,086,533</td>
<td>$1,586,408</td>
<td>$0</td>
<td>$0</td>
<td>$27,259,575</td>
</tr>
<tr>
<td>Distribution - Secondary</td>
<td>$19,234,824</td>
<td>$0</td>
<td>$4,829,300</td>
<td>$0</td>
<td>$1,229,538</td>
<td>$0</td>
<td>$0</td>
<td>$24,774,193</td>
</tr>
<tr>
<td>Customer</td>
<td>$30,513,005</td>
<td>$35,199</td>
<td>$2,414,789</td>
<td>$38,870</td>
<td>$10,636</td>
<td>$5,366</td>
<td>$7,155</td>
<td>$32,505,551</td>
</tr>
<tr>
<td>Total</td>
<td>$250,050,959</td>
<td>$869,307</td>
<td>$74,511,710</td>
<td>$63,191,760</td>
<td>$25,912,630</td>
<td>$20,523,170</td>
<td>$12,050,456</td>
<td>$443,473,710</td>
</tr>
</tbody>
</table>
Seasonal Differentiated Tariffs

• For most electric utilities in Missouri the summer months include June, July, August and September. The remaining eight months are considered winter months.

• For most gas utilities in Missouri the winter months are November, December, January, February and March and the remaining seven months are considered summer months. One gas utility is split evenly with six winter months and six summer months.

• Many Missouri electric utilities peak in the summer, therefore summer rates tend to be higher.

• All gas utilities in Missouri peak in the winter, therefore rates in the winter tend to be higher.
Rate Design Terminology

• Customer Charge = A monthly amount that is independent of usage. Also called a Basic Charge, Standing Charge or Meter Charge

• Energy Charges = A price per kWh of usage; may be in more than one time period, more than one block. May be seasonal or time-varying.

• Demand Charges = A monthly fee based on the highest instantaneous usage rate (usually highest hour) during the month or year. (Usually Commercial)
Residential Rate Types from Simple to Complex

- Declining Block- Lower Price for increase usage
- Flat Rate- Uniform rate per kWh for all usage
- Inclining Block- Higher Price for increase usage
- Seasonal- Higher in peak season
- TOU- Higher price for on-peak hours
- TOU w/ Inclining Block
- Critical Peak- A TOU that has a much higher price during a certain “critical peak” (requires AMI)
- Real-Time Pricing- A price that changes frequently based on market conditions. (requires AMI)
Residential Declining Block Rates

• ABC Utility Residential Rate (Sample)

Customer Charge $5.25

First 1000 kWh $0.087

Additional kWh $0.075

The more a customer uses the cheaper the electric becomes per kWh.
Declining Block Seasonal Rates

- Customer charge $9.50
- Summer $.10675
- Winter First 1000kWh $.08543
- Winter Over 1000kWh $.05234
Flat Rate Charge

- **Flat Rate/Seasonal Xcel Energy (Minnesota)**
  - Customer Charge       $ 8.00/month
  - Summer Energy         $0.0867/kWh
  - Winter Energy         $0.0739/kWh

- Most common in the United States of all utilities, approx. 3,000
- However, not as common with large regulated utilities
Inclining Block Rates

- **Residential Inclining Block Rate City of Palo Alto (California)**
- **Customer Charge** None
  - First 300 kWh $0.096/kWh
  - Next 300 kWh $0.130/kWh
  - Over 600 kWh $0.174/kWh
- Very common throughout the world
- To allocate low cost resources such as hydro plants in the first block.
<table>
<thead>
<tr>
<th>Usage Block</th>
<th>% of customers that usage ends in this block</th>
<th>% of kWh Sales To Customers Whose Usage Ends in This Block</th>
<th>% of kWh Sales To Customers Whose Usage Exceeds This Block</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-250</td>
<td>29%</td>
<td>8%</td>
<td>92%</td>
</tr>
<tr>
<td>251-500</td>
<td>33%</td>
<td>23%</td>
<td>69%</td>
</tr>
<tr>
<td>501-750</td>
<td>17%</td>
<td>20%</td>
<td>51%</td>
</tr>
<tr>
<td>751-1000</td>
<td>9%</td>
<td>15%</td>
<td>34%</td>
</tr>
<tr>
<td>over 1000</td>
<td>12%</td>
<td>34%</td>
<td>0%</td>
</tr>
</tbody>
</table>

Average Customer usage: 526

Source: RAP Energy Solutions: James Lazar

Small Southern California Town
Using Class Cost of Service To Determine Seasonal Rates

<table>
<thead>
<tr>
<th>Cost Category</th>
<th>Annual</th>
<th>Winter</th>
<th>Summer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production - Demand</td>
<td>$129,503,853</td>
<td>$65,562,446</td>
<td>$63,941,407</td>
</tr>
<tr>
<td>Production - Energy</td>
<td>$40,724,337</td>
<td>$23,528,727</td>
<td>$17,195,610</td>
</tr>
<tr>
<td>Transmission</td>
<td>$9,146,149</td>
<td>$4,880,785</td>
<td>$4,265,364</td>
</tr>
<tr>
<td>Distribution - Substations</td>
<td>$4,248,888</td>
<td>$2,031,530</td>
<td>$2,217,358</td>
</tr>
<tr>
<td>Distribution - Primary</td>
<td>$17,000,055</td>
<td>$8,128,274</td>
<td>$8,871,781</td>
</tr>
<tr>
<td>Distribution - Secondary</td>
<td>$18,991,533</td>
<td>$9,049,533</td>
<td>$9,942,000</td>
</tr>
<tr>
<td>Customer</td>
<td>$30,436,143</td>
<td>$20,290,762</td>
<td>$10,145,381</td>
</tr>
</tbody>
</table>

**Total Costs to be Recovered in Rates**
$250,050,959  $133,472,059  $116,578,900

<table>
<thead>
<tr>
<th></th>
<th>Residential</th>
</tr>
</thead>
<tbody>
<tr>
<td># of Customers</td>
<td>189,263</td>
</tr>
<tr>
<td>kWh @ Meter</td>
<td>1,904,348,334</td>
</tr>
<tr>
<td>Monthly Customer Charge</td>
<td>$13.40</td>
</tr>
<tr>
<td>Energy Costs</td>
<td>$0.0214</td>
</tr>
<tr>
<td>Demand Costs ($/kWh)</td>
<td>$0.0939</td>
</tr>
</tbody>
</table>
Time of Use Rate

- Time-of-use rates or time-of-day rates, are rates that change based on the time the energy is used.
  - In a 24-hour day the hours are designated as “On-peak” or “Off-peak” and sometimes a third option of “Shoulder”. A different rate applies to energy used at the designated times.
    - Provides an incentive to move energy usage from peak to off-peak hours.
    - Can be used for all classes of customers.
      - Especially for industrial customers
    - Hourly load research data is needed to determine hours of peak and off-peak usage and the level of usage within those hours.
# Sample Industrial Customer Tariff Sheet

## BILLING PERIODS

<table>
<thead>
<tr>
<th>Weekdays</th>
<th>Summer</th>
<th>Winter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>10:00 - 22:00</td>
<td>7:00 - 22:00</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>22:00 - 10:00</td>
<td>22:00 - 7:00</td>
</tr>
</tbody>
</table>

**Weekends**
- Off-Peak: All hours

## MONTHLY RATE (Secondary, Primary, Substation and Transmission)

<table>
<thead>
<tr>
<th></th>
<th>Summer</th>
<th>Winter</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Customer Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>First 500 kW</td>
<td>$1140.56</td>
<td>$1140.56</td>
</tr>
<tr>
<td>Over 500 kW</td>
<td>$1.81 per kW</td>
<td>$1.81 per kW</td>
</tr>
<tr>
<td><strong>Energy Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>$0.0607 per kWh</td>
<td>$0.0501 per kWh</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>$0.0427 per kWh</td>
<td>$0.0377 per kWh</td>
</tr>
<tr>
<td><strong>Billed Demand Charge</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>For each kW</td>
<td>$13.12 per kW</td>
<td>$5.60 per kW</td>
</tr>
</tbody>
</table>
Sample Large Customer Tariff Sheet (Cont’d)

• Metering Loss Adjustment
  – **Service Metered at Primary Voltage** – Where service is provided directly from a twelve (12) kV circuit feeder and is metered at four (4) kV or twelve (12) kV, the metered kWh and kW will be reduced by one and one-half percent (1.5%).
  – **Service Metered at Substation Voltage** – Where service is metered at four (4) kV or twelve (12) kV directly from a substation the metered kWh and kW will be reduced by two and one-half percent (2.5%).
  – **Service Metered at Transmission Voltage** – Where service is metered at thirty-four (34) kV and above directly from a transmission line, the metered kWh and kW will be reduced by three percent (3%).

• If there is no metering loss adjustment, there would be a separate tariff for each voltage level.
## Sample Residential Tariff Sheet

### BILLING PERIODS

<table>
<thead>
<tr>
<th>Weekdays</th>
<th>Summer</th>
<th>Winter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak</td>
<td>13:00 - 20:00</td>
<td>7:00 - 22:00</td>
</tr>
<tr>
<td>Shoulder</td>
<td>6:00 - 13:00</td>
<td></td>
</tr>
<tr>
<td>Shoulder</td>
<td>20:00 - 22:00</td>
<td></td>
</tr>
<tr>
<td>Off-Peak</td>
<td>22:00 - 6:00</td>
<td>22:00 - 7:00</td>
</tr>
</tbody>
</table>

**Weekends**

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Shoulder</td>
<td>6:00 - 22:00</td>
<td></td>
</tr>
<tr>
<td>Off-Peak</td>
<td>22:00 - 6:00</td>
<td>All hours</td>
</tr>
</tbody>
</table>

### MONTHLY RATE

<table>
<thead>
<tr>
<th></th>
<th>Summer</th>
<th>Winter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Charge</td>
<td>$18.46 per month</td>
<td>$18.46 per month</td>
</tr>
<tr>
<td>Energy Charge</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>$0.2036 per kWh</td>
<td>$0.1307 per kWh</td>
</tr>
<tr>
<td>Shoulder</td>
<td>$0.1131 per kWh</td>
<td></td>
</tr>
<tr>
<td>Off-Peak</td>
<td>$0.0679 per kWh</td>
<td>$0.0522 per kWh</td>
</tr>
</tbody>
</table>
Decoupling

1. What is decoupling? In the electricity and gas sectors, “decoupling” (or “revenue decoupling”) is a generic term for a rate adjustment mechanism that separates (decouples) an electric or gas utility’s fixed cost\(^1\) recovery from the amount of electricity or gas it sells. Under decoupling, utilities collect revenues based on the regulatory determined revenue requirement, most often on a per customer basis.
Decoupling cont.

On a periodic basis revenues are “trued-up” to the predetermined revenue requirement using an automatic rate adjustment. The result is that the actual utility revenues should more closely track its projected revenue requirements, and should not increase or decrease with changes in sales.
Decoupling cont.

Since utilities will be protected if their sales decline because of efficiency, proponents of decoupling contend that they are more likely to invest in this resource, or may be less likely to resist deployment of otherwise economically beneficial efficiency.
Questions?

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